COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Investigation by the Department of Telecommunications	**)**	
And Energy on its own motion, pursuant to GL c. 164	**)**	
§§ 76, 94 and 94A, to investigate the appropriateness	**)**	
of the use of Risk-Management Techniques to mitigate	**)**	**DTE 01-100**
Natural Gas Price Volatility	**)**	
for approval of an amendment to a gas	**)**	
supply contract pursuant to MGL c. 164 § 94A	**)**	

COMMENTS OF THE COMMONWEALTH OF MASSACHUSETTS DIVISION OF ENERGY RESOURCES

I. INTRODUCTION

In D.T.E. 98-32-B, the Department defined a fully functional competitive market as one in which competition is available to and used by all natural gas consumers and one in which the LDCs are relieved from their obligation to plan for and procure capacity and supply resources. DOER's vision of a fully competitive gas industry is the same as the Department envisioned in D.T.E 98-32-B. DOER envisions a market in which all customers have the following: 1) the option to purchase gas, interstate transportation and other upstream services from a multitude of suppliers; 2) LDCs are no longer required to provide supply or capacity to the city gate; 3) LDCs provide intrastate transportation services only; and, 4) LDCs are entirely out of the merchant function. DOER believes this kind of competitive market will provide the best conditions for both buyers and sellers of natural gas in Massachusetts.

To that end, DOER has consistently supported gas unbundling and customer choice in the natural gas industry and has promoted competition from the well head to the city gate to the burner tip. DOER supports the continued efforts of the Department and stakeholders within the natural gas industry to form a fully competitive retail market in which competitive retail options will be available to all classes of customers.[1] Competition creates better products, better services and lower prices for customers. Therefore, DOER applauds the Department's efforts in DTE 01-100[2]. Regarding the issues presented in DTE 01-100, the expansion of the risk-management techniques to mitigate natural gas price volatility, DOER supports the use of such techniques subject to certain restrictions.

A prudent and effective LDC risk-management program hedges against unexpected price increases and limits price swings to those customers who have not yet been able to obtain the benefits of market competition. Such a program should limit future price increases like those of last winter. It should also prevent future price swings like those of the past couple years.[3] The type of risk-management program outlined by DOER in

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[1] Retail competition within the Massachusetts natural gas industry has been reasonably active, at least for the industry's largest customers. Monthly migration data provided by the largest LDCs (Keyspan Energy Delivery, Bay State Gas and NSTAR Gas) to DOER indicate that, depending on the specific LDC, approximately 45 to 85 percent of the largest commercial and industrial customers have migrated to the LDC's firm transportation-only service, purchasing a marketer's competitive gas supply rather than the LDC's default service. This migration suggests retail competition can and will continue to generate significant benefits to certain customers. However, not all customers in Massachusetts have reaped the benefits of retail competition in the unbundled era. Significant numbers of small commercial, industrial and residential natural gas customers have not migrated. The LDC-provided migration data to DOER reveal only about five percent of small commercial and industrial customers and less than one-half of one percent of residential customers have migrated. In fact, many small customers who tried firm transportation and a competitive marketer's supply have migrated back to the LDC's default service. For example, the number of small commercial, industrial and residential customers in the Bay State Gas service territory choosing firm transportation and a marketers gas supply has decreased from over 20,000 to less than 1,000. Bay State has approximately 250,000 small customers. It appears retail competition for these customers has not been very active and will not avail itself any time soon. Clearly, there will be an extended transition period for small customers to migrate to a more competitive environment. In addition, LDC's still have their supply obligation for the remainder of the transition period. Because of these facts, DOER believes LDCs should provide default service in the best manner possible to those customers who remain on it. Allowing LDC risk-management programs to include a few simple hedging tools will improve default service to those customers who do not yet have a competitive option.

[2] Investigation by the Department of Telecommunications and Energy on its own motion, pursuant to GL c. 164 §§ 76, 94 and 94A, to investigate the appropriateness of the use of Risk-Management Techniques to Mitigate Natural Gas Price Volatiltiy.

[3] A certain degree of price movement in LDC default services may be helpful in developing a competitive market by allowing marketers and competitive suppliers to provide products and services that smooth out price movements. However, extreme and unforeseen price increases and volatility, combined with a lack of competitive alternatives for

these responses is intended for default service customers who remain, and will continue to remain, on the LDC's system until the end of the five-year transition period set by the Department in D.T.E. 98-32-B ("the transition period"), or such time as the natural gas market in Massachusetts is competitive and alternate suppliers are available to all of the LDC's customers.

Accordingly, DOER recommends that the Department allow LDCs to expand their gas supply procurement and acquisition strategies to include a diversified mix of purchase options composed of those financial transactions that limit price increases and foster price stability as described herein.

II. EXECUTIVE SUMMARY

DTE 01-100 posed nine questions regarding the use of risk-management techniques by natural gas distribution companies. DOER has provided detailed responses to each of the questions posed in Section III below. The Division's positions with respect to each issue presented in DTE 01-100 are briefly summarized below.

1) Should Massachusetts gas utilities be allowed or required to implement a risk-management program to mitigate price volatility for gas customers?

   DOER believes that LDCs should be allowed to expand their current risk management programs and mitigate price spikes and volatility.

2) How will risk-management by LDCs affect gas unbundling and customer choice in Massachusetts?

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certain customers, may impose higher costs on those customers yet do little or nothing to expand competitive offerings. On account of this, DOER believes default service customers may benefit from LDCs hedging against price increases and volatility during the transition period to a complete and open market for all Massachusetts natural gas customers.

DOER does not believe that the implementation of expanded risk-management programs as outlined in Section III herein will negatively impact gas unbundling or customer choice.

3) Should LDCs be limited to specific types of risk-management techniques? If so what types?

   DOER believes that the Department should restrict the types of expanded risk-management techniques to those financial hedges that are most commonly used within the natural gas industry because they will be the most liquid and efficiently traded. These techniques include call options, collars and swaps.

4) Should there be a specific limit to the percentage of gas volume that LDCs should be allowed to hedge?

   DOER believes that the Department should restrict the expanded LDC risk management activities to between 50 to 75 percent of their normal flowing indexed-based winter gas supplies, subject to a cost cap. Such cost cap should be 2% of each respective LDC's annual default service revenue.

5) What should the core objectives of a hedging program be? (e.g. least-cost, price stability)

   DOER believes the core objectives of a hedging program should be to minimize price spikes and stabilize LDC prices. Simplicity in design, administration and review should also be core objectives.

6) How will the Department assess risk-management programs? What benchmarks should be used to measure a risk-management program's performance?

   DOER believes that the Department should develop objective benchmarks that reflect the goals of the program at the very least. DOER has recommended specific examples of such benchmarks and how the risk-management programs should be assessed against such in Section III below.

7) What standard of review should the Department apply to the LDCs' initial risk-management program?

   DOER believes that the standard of review should reflect the broad general principles underlying the implementation of the risk-management programs. In Section III DOER has identified specific review questions that could be considered in the Department's review.

8) What types of costs are associated with risk-management? Should LDCs be allowed to recover these costs? If so, please explain how.

   The following costs are associated with price hedging: brokerage fees, related transactional and financing costs and premiums. Also, there are gains and losses on some purchases relative to the physical acquisition. DOER believes all of these costs should be eligible for recovery by the LDC in the CGAC as explained in Section III.

9) Should an incentive mechanism be used in conjunction with a risk-management program? If so, please explain how this mechanism should be structured.

   As described in Section II below, DOER does not support the implementation of incentive mechanisms.

Detailed responses supporting the positions stated in response to the above questions are provided below in Section III.

SECTION III. DOER RESPONSES TO DTE 01-100 QUESTIONS

1) **Should Massachusetts gas utilities be allowed or required to implement a risk-management program to mitigate price volatility for gas customers?**

The Massachusetts Division of Energy Resources ("DOER") recommends the Massachusetts Department of Telecommunication and Energy ("Department") allow Massachusetts natural gas distribution utilities ("LDCs") to expand their current risk-management programs to include additional financial transactions (described in response to question 3) in their gas supply acquisition strategy[4] that will mitigate extreme price increases and volatility.

Obtaining price stability is a prudent business practice. It allows the producer to adequately project and manage his costs of production. It allows the consumer to manage his fiscal budget. For the energy industry stable prices are beneficial because it is not easy for the majority of customers to switch fuels or suppliers if prices spike up and down. Only the largest consumers of energy can switch quickly. Furthermore, LDC price stability will give competing marketers and suppliers a more stationary target price,

[4] Current LDC risk-management programs include some limited physical and financial hedging tools. See DOER response to question 3, below.

making it easier for the competition to market their prices and services to remaining default service customers[5].

In addition to addressing the above practical concerns, price stability for regulated LDCs is a rate-making goal of the Department. In the most recent LDC rate order issued by the Department[6], this goal was emphasized once again in setting the approved rates.

The need for meeting the goal of price stability is reflected in the behavior of the national and regional natural gas markets. On a national basis, natural gas prices have become increasingly volatile. In the early 1990s[7], wellhead prices for January ranged from $1.75 to $2.25 per MMBtu. In the mid-1990's[8], the January prices ranged from $1.60 to $3.40 per MMBtu. Over the last few years[9], the January prices ranged from $2.35 to $10.00 per MMBtu, an increase and decrease of over three-fold. Wellhead price volatility creates price volatility for the LDCs.

On a regional basis, natural gas prices have also been highly volatile. According to *Gas Daily*, the monthly contract index price for gas delivered to New England city gates over the last two years rose from an average of $2.95 per MMBtu in January, 2000, to $13.75 per MMBtu in January, 2001, and back down to $3.50 per MMBtu for January, 2002. This regional price volatility also creates price volatility for the LDCs. The implementation of price-hedging tools in LDC risk-management programs will help mitigate market fluctuations and achieve the goal of price stability.[10]

[5] An example of this in the energy industry is the monthly electric default service pricing that is known up to six months in advance.
[6] D.T.E. 01-50, Blackstone Gas Company
[7] 1990 – 1992, data from the Energy Information Administration ("EIA").
[8] 1995 – 1997, data from EIA.
[9] 2000 – 2002, data from *Gas Daily*, monthly contract index prices at Henry Hub.
[10] While it is true the interstate pipeline infrastructure has increased significantly over the last couple years bringing new supplies into New England, it is expected that the demand for natural gas by new electric generators coming on line will

Other state jurisdictions that have addressed this issue have allowed LDCs to implement hedging mechanisms. According to a recent study conducted by the National Association of Regulatory Utilities Commissioners' Staff and the National Regulatory Research Institute ("NNRI") [11], 21 of the 28 state PUCs surveyed allow LDCs to use price hedging in their gas supply acquisition strategies. Five of the seven states not currently using hedging are investigating the benefits of hedging. The survey results clearly demonstrate that state regulators around the country believe price hedging is a beneficial practice.

Accordingly, DOER believes that ensuring LDC price stability should be beneficial to all participants in the Massachusetts natural gas industry and recommends that the Department allow LDCs to expand their risk-management programs to include some specific price hedging tools (see DOER response to question 3), and to allow the implementation of such tools in a timely manner.

2) **How will risk-management by LDCs affect gas unbundling and customer choice in Massachusetts?**

DOER believes expanding LDC risk management programs in the limited manner described herein should not significantly impact gas unbundling and customer choice because the vast majority of an LDC's current default service customers are small and

be just as significant. A 2001 report done by Levitan and Associates, Inc. for the ISO New England, Inc. reveals that, by 2005, natural gas fired electric energy is projected to increase from 16% to 45%. Given these conditions it is anticipated that supply and demand imbalances for natural gas in the region should continue, and unexpected price spikes and volatility could recur. The use of hedging tools by LDCs in purchasing gas supplies can help to stabilize such unexpected price disturbances.

[11] State Responses to Last Winter's High Natural Gas Prices and Consideration of Hedging and Other Risk Management Activities, August 2001, compiled by NRRI.

have virtually no choice at this time.[12] Since no choice presently exist for these customers, implementation of the suggested expanded risk-management programs will not affect customer choice. Furthermore, the move to a fully open and competitive market for these customers will take some time, and the remainder of the transition period (the period for which DOER is recommending the risk-management programs be implemented) is short. Given the short program period relative to the anticipated period associated with the development of a competitive market for small commercial/industrial/residential consumers, it is not anticipated that the implementation of the programs will negatively impact customer choice. In addition, expanding LDC risk-management programs certainly will not prevent marketers and competitive suppliers from offering alternative hedging products to natural gas consumers.[13]

3) **Should gas utilities be limited to specific types of risk-management instruments? If so, what types?**

DOER believes LDCs should be limited to specific types of risk-management and hedging instruments.[14] As a general principle DOER recommends that allowed hedging tools and techniques be limited to those that are most commonly used within the natural gas industry because they will be the most liquid and efficiently traded. Since most LDCs may have little or no experience with most financial hedging tools and techniques,

[12] A recent *Gas Daily* story entitled "Gas Marketers Closing Door to Homeowners" indicated that gas marketers to small customers continue to vanish from retail choice programs.
[13] However, it is critical that all hedging costs be borne by those customers using these products so that marketers and competitive suppliers can offer hedging products to those used by the LDCs that compete against the true cost of the LDC hedging products.
[14] As mentioned in response to question 1 above, LDCs currently make use of some physical hedging techniques. For example, they purchase supply during the summer time, store it in upstream underground and on-system facilities and dispatch during the winter time. This is a hedge in which a supply (usually priced lower) is bought for dispatch at a future date. This technique can amount to over 25 percent of an LDC's normal winter supply requirements. Another physical hedge used by LDCs is the purchase of supply from different supply basins, like the U.S. Gulf Coast, West Texas, western Canada and Nova Scotia. Purchasing supply from many basins can moderate locational price disturbances. LDCs also make use of some financial hedges. An example of a financial hedge used by LDCs is buying a supply based on a first-of-the-month price. This short-term hedge allows the LDC to purchase a month's supply at a fixed price. DOER

DOER recommends the LDCs and the Department take a conservative and simple hedging approach in this initial stage of the transition period. To that end, DOER recommends that the Department allow the LDCs to include a limited number of financial hedging tools in their respective gas supply portfolio risk-management plans. These tools include the following types of hedging tools:

1) Call options[15] - These give the holder the right to buy a specified amount of gas at a pre-determined or strike price between the date of purchase and the option's expiration date. This hedging tool insures against high and escalating prices by setting a ceiling price for supply.

2) Collars – These are a combination of a call option and a put option. A put option gives the holder the right to sell a specified amount of gas at a predetermined or strike price on or before the expiration date of the contract. A collar can result in no cost if the up-front call premium paid equals the up-front put premium collected. This hedging tool constrains the purchase price within a range of prices and limits price volatility.

3) Swaps – These are agreements between two parties to exchange periodic payments to one another; one party pays a fixed payment and the other a floating payment over a set term, quantity and price. This hedging techniques locks in a fixed supply price thereby eliminating price increases and volatility.

believes LDCs should continue to employ these and the other types of physical and financial hedging techniques currently used because they mitigate price increases and volatility to some degree.

Although DOER believes there is value to the use of the above financial hedging mechanisms, the Division notes that there are risks associated with each.[16] For instance, while a call option limits price to a ceiling there is a cost associated with the hedge. The collar, while limiting the associated cost risk and ensuring supply prices do not move outside of a specific range thereby preventing price spikes, does not allow the LDC and its customers to participate in significant price decreases. The swap, while fixing the price, prevents price increases but does not allow for price decreases. Based on the limited risk associated with each of the above hedging mechanisms, DOER recommends that LDC risk-management programs should incorporate a combination of these financial tools in designing a gas supply portfolio. A diversified mix of financial (and physical) hedges will spread the costs and benefits of each specific hedging tool over the entire risk-management program. However, due to the benefit of providing certainty with respect to maximum prices, thereby protecting consumers against price spikes, DOER recommends that LDC risk-management portfolios implement a bias (i.e., incur most of their allotted costs) towards the use of call options.

DOER also believes that LDCs should be allowed to hedge basis risk to some degree, provided the market for basis risk is liquid. Basis risk is the difference in value between the price of gas at the NYMEX trading point, Henry Hub, and another trading location. Most LDCs take their domestic flowing gas supply at several physical locations in the supply area, which is the U.S. Gulf coast. Other physical take locations can be much further downstream towards the market area on the interstate pipeline system.

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[15] An option is a contract between two parties in which one party has the right but not the obligation to buy or sell gas, usually in exchange for an up-front premium.

[16] DOER recognizes that any LDC risk-management program that includes financial hedges may result in higher average gas costs or lower average gas costs than would result had no hedging been put in place and prices were set at the market rate. However, DOER believes a prudent and effective hedging program should help mitigate price spikes to default service customers, result in a greater level of certainty about natural gas prices, and provide a more stable target price for marketers and competitive suppliers to compete against.

Therefore, in many instances, although the LDC might purchase a NYMEX hedge, the physical supply will be bought at a price that is different because it will be located away from Henry Hub. Since the price is not completely hedged, purchasing basis ahead of time appears reasonable, so long as the market for it is liquid.

In addition to restricting the types of financial hedging mechanisms a LDC may use, DOER recommends that the Department impose some program restrictions.

LDC's risk-management program should not include speculative transactions. Accordingly, the program should reflect a mix of hedge positions that are implemented at several objective dates and maturities. A systematic dollar-cost-average approach to supply purchase diversifies and moderates the effect of each hedge position on the overall price realized under the program and provides a safeguard against speculation. Therefore, DOER recommends minimum and maximum amounts of supply be hedged by pre-determined specific dates, or when certain target prices are met, and the flowing supply be hedged by the start of the winter season. This sort of dollar-cost averaging, in which fixed amounts are hedged on a regular basis, reduces the speculative nature of gas purchasing. By eliminating subjective discretion with respect to timing, systematic purchases provide a safeguard against trying to time the market. Prices are unpredictable, implementing hedges at objective, regular intervals eliminates subjective speculation.

While certain hedging activities can be implemented based on objective criteria, as described above, DOER acknowledges that each LDC in Massachusetts is somewhat unique.[17] Each has its own customer base, load curves, peaking requirements, facilities and contract suppliers. Therefore, DOER believes each LDC may require a different percentage or range of percentages of supply to be hedged and a different schedule for purchasing the full amount of price hedges. Accordingly, DOER believes the LDC hedging programs will need to be designed to account for the specific circumstances relative to each LDC. In establishing the subjective program parameters DOER recommends that the Department consider the following issues for each LDC: 1) a range of supply that can be hedged; 2) time intervals and target prices for the purchase and/or sale of the hedging products; 3) a limit on the total cost of the hedges; and, 4) other broad objectives and guidelines that should be followed.

4) **Should there be a specific limit to the percentage of gas volume that LDCs should be allowed to hedge?**

LDCs should be required to financially hedge a significant majority, between one-half to three-quarters, of their flowing index-based winter supplies necessary to meet normal firm default service customer demands. Hedging a lesser or greater volume on the expectation of abnormal temperatures amounts to speculating.[18]

DOER acknowledges that there is an associated cost with the implementation of financial hedging mechanisms. In light of the potential cost, DOER recommends that hedging programs be limited to a cost of no more than 2% of the LDC's total annual

[17] DOER recognizes a few Massachusetts LDCs are small and may not be able to capture some economies of scale or develop an effective risk-management program. If appropriate, these LDCs may have to petition the Department in order to combine with an affiliated or other LDC to develop a prudent program.
[18] Setting a percentage below 100 percent is a conservative approach and prevents the LDC from hedging more supply than is required during a warm winter.

default service revenue. DOER believes paying such a small premium for a potential ceiling price is reasonable.[19]

5) **What should the core objectives of a hedging program be (e.g., least cost, price stability)?**

DOER believes the primary objectives of a LDC hedging program are to minimize unexpected short-term price spikes and to stabilize the price of LDC gas purchases required to provide default service.[20] Default service prices resulting from a prudent and effective risk-management program should yield less volatility than market prices.

Another key objective of a LDC hedging program is simplicity. It is counter-productive to implement a complicated hedging program where the benefits are exceeded by administration and review costs. Simplicity can be achieved by limiting the risk-management plans to the use of the hedging tools discussed herein. In the future, if it is found that hedging strategies with more complex tools, techniques and timelines can provide additional benefits, risk-management programs can be modified to include such additional methods.

6) **How will the Department assess risk-management programs? What benchmarks should be used to measure a risk-management program's performance?**

[19] The average winter monthly bill impact of a two percent increase on residential heating customers is less than $3.50.

[20] The use of hedging tools may not reduce the cost of an LDC's gas supply due to the cost of purchasing the hedge. However, they can reduce unexpected price increases and volatility.

DOER believes that benchmarks to assess the results of the LDC's risk management program could be set. DOER recommends these benchmarks be basic and reflect the core objectives of the program.

For example, as stated in response to question 5, above, DOER believes the main objective of a LDC's risk-management program is to limit unexpected short-term price spikes. Accordingly, one appropriate measure to asses the program results could be an examination of the prices at which the LDC purchased supply when market prices spiked significantly above average historical levels. The purchased or strike price should be lower than the market price.[21]

The second objective of the risk-management program, as recommended by DOER, is to stabilize the price of gas purchases a LDC must make to serve its default service customers. For this objective the program results could be assessed by an examination of the standard deviations in actual supply purchase prices compared to market prices. The standard deviation in actual prices should not be higher than that for market prices.

Regarding the time period that should be used to assess the programs, DOER believes the programs should be evaluated over a few seasons. Single seasons are susceptible to event risk as evidenced by the events of last winter. To achieve a fair and accurate evaluation, DOER recommends that the Department assess the LDC expanded risk-management programs at the end of the transition period.

[21] Any savings will equal the difference in prices multiplied by the amount of MMBtus purchased less the costs of the call options.

7) **What standard of review should the Department apply to the LDCs' initial risk-management program?**

DOER is recommending that the expanded LDC risk-management programs be simple in strategy and in the types of price hedges purchased/used. Therefore, DOER recommends that the Department implement a simple review framework for a LDC's risk-management program that reflects broad, general principles.

To accomplish this, the Department's review could include a series of yes/no questions to LDCs regarding their risk-management programs. The responses to the questions would provide the Department with the means to accomplish an objective review of the subjective programs. DOER recommends the following questions:

1) Did the LDC limit its program costs to the company-specific percent of total annual default service revenue allowed by the Department?

2) Did the LDC financially hedge an amount of supply that falls within the allowed range?

3) Did the LDC include a call-option bias in its hedging purchases?

4) Did the LDC fall within the maximum and minimum amounts of supply allowed to be financially hedged by the beginning of the winter?

5) Did the LDC systematically purchase within the maximum and minimum amounts of supply allowed to be financially hedged according to a set of scheduled dates prior to the beginning of the winter?

6) Did the LDC systematically purchase within the maximum and minimum amounts of supply allowed to be financially hedged according to any pre-set price targets?

7) Did the LDC control price volatility consistent with other LDC programs or benchmarks set by the Department?

If a company's answers to the questions are affirmative, and the LDC stayed within any other guidelines set and approved by the Department, then DOER believes the LDCs risk-management program should be deemed reasonable and the LDC should be allowed to collect the costs incurred in managing the program from its default service customers.

Regarding the review period, DOER recommends these expanded programs remain in place for the remainder of the transition period. This transition period should allow the market to progress towards a retail market in Massachusetts that is fully functional and competitive. This time period will also enable the Department and other stakeholders to determine if these programs can provide the anticipated benefits, and will allow for the simultaneous evaluation of the working conditions of the natural gas market in Massachusetts (since the unbundling order) and the measurement of any detrimental effects these programs may have on the development of a fully competitive market for all natural gas consumers (especially the small commercial, industrial and residential customers).

After the review period, if LDC expanded risk-management programs are not providing the anticipated benefits, or the programs are an obstruction to an open natural gas market, the Department can modify or terminate them. If the programs are deemed beneficial, as DOER anticipates, and do not create barriers to competition, the Department can extend them into the future until the market is fully competitive and the LDCs are entirely out of the merchant function.

Finally, to ensure transparency for all market participants and minimize risk to consumers DOER also recommends that hedging programs be administered in accordance with appropriate accounting standards prescribed by the Department with complete financial reporting and disclosure of the program at all times.

8) **What types of costs are associated with risk management? Should LDCs be allowed to recover these costs? If so, please explain how.**

There are a variety of costs associated with a prudent and effective risk-management program. There is the cost of the hedge. Brokerage fee costs are incurred. Related transactional and financing costs exist. Call options include the premium cost. Puts, the other half of a collar, include revenue due to a sale. There are gains and losses on some purchases relative to the physical acquisition. DOER believes all these costs should be eligible for recovery by the LDC.[22]

[22] It should be noted that, as stated before, DOER believes the costs of an LDC's risk-management program, exclusive of the gains and losses on purchases, should be capped. LDCs should not be allowed to incur costs greater than two

DOER recommends the costs associated with a prudent and effective risk-management program be collected through the LDC's Cost of Gas Adjustment Clause. The incurred costs should be recovered on a per MMBtu basis from default service customers over the entire year.

9) **Should an incentive mechanism be used in conjunction with a risk-management program? If so, please explain how this mechanism should be structured.**

DOER does not support an incentive mechanism in conjunction with expanded LDC risk-management programs because the recommended program is more similar to buying an insurance policy against price spikes and volatility.[23] Insurance policies should not have incentive clauses.

Another reason for not allowing incentive mechanisms at this time is that the LDCs, the Department, and the other stakeholders, including DOER, have virtually no experience with the hedging tools and techniques promoted in these responses. Due to this lack of experience, it would be difficult for any stakeholder to define a fair and reasonable incentive benchmark.

Furthermore, DOER can not support an incentive mechanism at this time because of the magnitude of the potential costs and savings. A LDC's purchased gas costs are the vast

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percent of their total annual default service revenue. The majority of costs subject to the cap should be those asociated with the purchase of out-of-the-money call options which protect against price spikes.

[23] It should be noted that although DOER does not support allowance of an incentive mechanism in this instance DOER supports incentive regulation in principle. It has supported such in several Department proceedings. DOER believes that

majority of their expenses and dwarf the LDC's allowed return on equity.[24] An inappropriate incentive mechanism could result in significant negative repercussions for the LDC or its customers. DOER believes that without adequate experience, the risk factor and the potential costs of including an incentive mechanism in a LDC risk-management program far outweigh the potential benefits.

Finally, as the Department stated in D.T.E. 98-32-B, a fully competitive natural gas industry is one in which all customers have the option to purchase gas from a wide range of providers and LDCs are no longer required to serve as gas merchants to all customers downstream of the city gate and are responsible only for the local distribution function. DOER believes that giving LDCs an incentive mechanism in their risk management programs will provide a disincentive for LDCs to move out of the merchant function obligation. Continued LDC provision of the merchant gas function will hinder movement/progression towards the Department's definition of a competitive marketplace. Accordingly, DOER believes the Department should take a conservative approach at this time and not allow for an incentive mechanism.[25]

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including incentives in performance-based regulation, in many instances, results in a better, more efficient industry than that which results from standard cost-of-service regulation.

[24] In a recent rate case filing before the Department, the LDC's annual purchased gas costs exceeded its proposed return on equity by a factor of over six.

[25] It is possible that, during the later phases of the transition period to a fully competitive market, a supportable and reasonable limited incentive mechanism may be permissible provided the LDCs are still required to provide the natural gas merchant function, the incentive is small and, most importantly, the mechanism does not create an obstacle to the development of an open and competitive natural gas market for all Massachusetts consumers.

Respectfully submitted,

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